Natural Gas Desulfurization Process By MEA Amine: The preferable Engineering Design Procedure

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Abstract — *Natural gas may consider the most popular energy source in recent era and the demand for it in recent years has been dramatic. However, natural gas is existed in deep reservoirs so it may contents many impurities for instance, hydrogen sulphide, carbon dioxide and mercury. Indeed, these impurities may cause several technical problems for instance, corrosion and environment pollution. Therefore, raw natural gas should be purify before processing it to global gas markets and amine gas sweetening process may consider the most common technology to remove acid gases from natural gas stream. Thus, this study aims to treat a given composition natural gas stream with a moderate hydrogen sulphide contents about 2500ppm vie engineering mathematical calculations for MEA circulation rate that was about 490 gpm. The amine circulation rate is considered quite important amine gas sweetening parameters that should be at optimum value to achieve optimum acid gas removal and meet the product requirement. Thus, the amine circulation rate examined by material balance calculations for amine contactor tower. As a result, it is found that 490 gpm amine circulation rate is an effective value to reduce hydrogen sulphide contents to 4ppm which it meets the gas pipelines and gas sell contracts specification.*

Keyword — *Natural gas sweetening, amine solution, amine circulation rate, acid gas, absorber tower.*

I. Introduction

Natural gas has an important role in the recent world development. However, natural gas usually contents acid gases for example, H_2S and CO_2 that it needs to be removed from natural gas to meet the gas pipelines specifications. Stewart and Arnold (2011) note that gas contracts restrict H_2S content about 4ppm and CO_2 about 2% in natural gas stream. Thus, many gas sweetening processes developed to remove acid gases from raw natural gas stream for example, chemical absorption, solid bet sweetening method and physical absorption method. However, amine gas sweetening is considered the most popular process among natural gas sweetening methods. In fact, amine gas sweetening process has several advantages for example, continues process, the ability to regenerate the process solvent. However, any amine process has many operation conditions for instance amine contactor pressure, amine solution concentration and amine circulation rate. In fact, amine circulation rate is considered one of the most important amine process operation conditions that has huge effect on acid gas removal from natural gas stream. It quite important to adopt the correct amine circulation rate to achieve optimum acid gas removal and meet product requirement.

II. Basic amine process description

Amine gas sweetening process is shown in figure 1.Firstly, sour gas stream is usually enters to scrubber to remove sour gas constants. Secondly, sour gas enters to the bottom side of amine absorber tower and flow countercurrent to amine solvent and Sweet gas will leave the top of the contactor tower and need to be processed to dehydration process to remove saturated water. Moreover, Dirty or rich amine will leave bottom of contactor tower and need to be regenerate. Finally, Amine stripping tower (regenerator) is used to regenerate the dirty amine hot lean amine need to be cooled therefore it flows to amine heat exchanger and then back to contactor tower. The brief of amine process could be described as following:

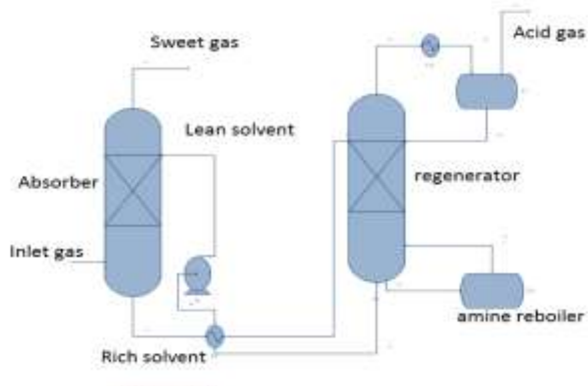

Figure 1: General flow diagram for Amine plant

III. Case study

The case study gas composition is shown in table 1. It seems that the gas has a moderate content of acid gases. However, the gas analyzed on dry basis. Therefore, gas water content should be calculated.

Table 1: Given Case study tow data.

		Component	Mole %
Case study		CH_4	91.68
		C_2H_6	3.05
		C_3H_8	0.76
		C_4H_{10}	0.26
Acid gas level content	Moderate	CO_2	1.2
Gas flow rate(stm³/day)	2850000	H_2S	0.25
Temperature C°	26	N_2	2.8
Pressure (bar)	75	H_2O	-

Natural gas water content can be estimated by adopting the McKetta-Wehe Chart [3]. Therefore, the raw natural gas water content is about $= 482 \frac{kg}{MMstd\,m^3}$.

Now, the new Natural gas composition could calculate and summarized as shown in table 2.

Table 2: natural gas composition.

Component	Mole%	Kmole/day	RMM	Kg/day	Mole%
CH_4	91.68	116573.6	16.02	1867509	91.62512
C_2H_6	3.05	3878.157	30.07	116616.2	3.048174
C_3H_8	0.76	966.3603	44.09	42606.83	0.759545
C_4H_{10}	0.26	330.5969	58.12	19214.29	0.259844
CO_2	1.2	1525.832	44.01	67151.87	1.199282
H_2S	0.25	317.8817	34.076	10832.14	0.24985
N_2	2.8	3560.275	28.02	99758.9	2.798324
H_2O	-	76.15833	18	1370.85	0.059859
Total	100	127228.8		2225060	100

IV. Amine circulation rate

Amine circulation rate is considered one of the most important parameters with regards the reduction of acid gas quantity in natural gas. Moreover, many researchers have developed numerous methods to calculate the circulation rate for amine gas sweetening. However, Campbell 1979 has put forth a useful procedure with which to calculate amine circulation rate. In this work MEA (15% w/w) will be used for the amine gas sweetening process. As Campbell (1979) and Kohl & Riesenfield (1997) recommend, a 75% approach to the equilibrium concentration should be used for the design propos. However, in contrast, Zapffe recommends 65%, whilst Campbell (1979) recommends using the average of both approaches. With these recommendations taken into account, 70% will be used. Moreover, As Khol & Riesenfield (1997) note, "rich amines can be adequately stripped with 0.9 to 1.2 pounds of steam per gallon of rich solution". Therefore, for this work $0.9 \frac{lb\ of\ steam}{US\ gal\ of\ MEA}$. For given gas composition the acid gas ratio is: Acid gas ratio$= \frac{H2S\%}{CO2\%} = 0.2079$.

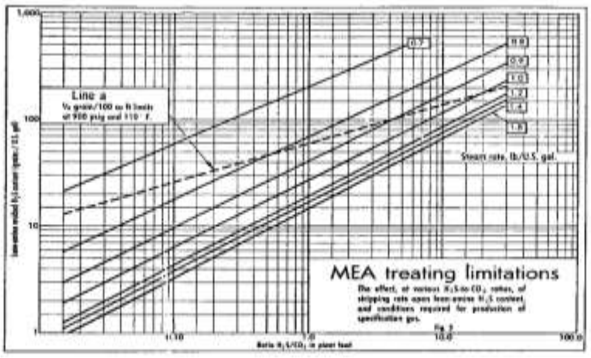

Figure 2: Residual H_2S [4].

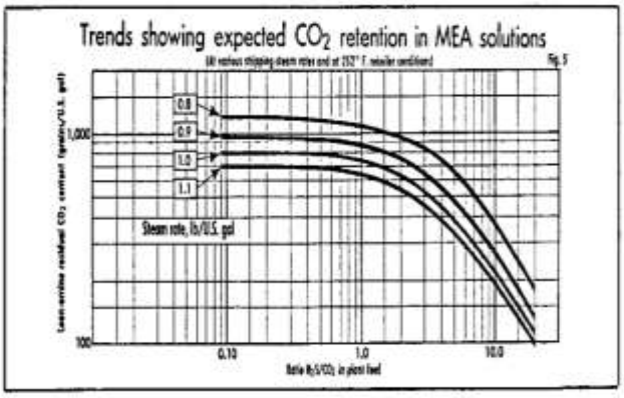

Figure 3: Residual CO_2 [4].

From figure 2, residual H_2S can be calculated by using the ratio. Thus, $H_2S = 18\frac{grains}{gal}$

$$Residual\ H_2S = 18\ \frac{grains}{gal} * \frac{1\ lb}{7000\ grains} = 0.002577\ \frac{lb}{gal\ MEA}\ concintration\ of\ residual\ H_2S$$

Dividing the above amount by MEA molecular weight to obtain $Residual\ H_2S\ \frac{lbmole}{gal\ MEA}$

Thus

$$,Residual\ H_2S = \frac{0.002577}{34} = 0.0000757\ \frac{lbmole}{gal\ MEA}$$

Residual CO_2 can also be calculated from the graph in Figure 3, by maintaining the same procedure: $Co_2 = 890\frac{grains}{gal}$

$$Residual\ CO_2 = 890\ \frac{grains}{gal} x \frac{1\ lb}{7000\ grains} = 0.1272\ \frac{lb}{gal\ MEA}\ concintration\ of\ residual\ CO2$$

Dividing the above amount by MEA molecular weight to obtain $Residual\ CO_2\ \frac{lbmole}{gal\ MEA}$

Thus, $Residual\ CO_2 = \frac{0.1272}{44} = 0.0029\ \frac{lbmole}{gal\ MEA}$

Total residual acid gas= $0.0000757 + 0.0029 = 0.00298\ \frac{lbmole}{gal\ MEA}$

Density MEA at 38°C = 1003 Kg/ m^3 (CHEM Group, 2012).

Density of water at 38°C = 999.3 kg / m^3 (Claude, 2000)

Thus density of solution = (0.15 × 1003) + (0.85 × 999.3) =999.8 $\frac{kg}{m^3}$

$$999.8\ \frac{Kg}{m^3} \times 2.204622\ \frac{lb}{Kg} \times \frac{1\ m^3}{264.172\ (us)\ gal} = 8.35\ \frac{lb}{gal}$$

(Density of MEA)

Taking the density of 15% of MEA to be $8.35\ \frac{lb}{gal}$, there will be:

$0.15 \times 0.99 \times 8.35 = 1.24\ \frac{lb}{gal}$,

$MEA\ Mwt = 61.08 \frac{lb}{lbmole}$ .Thus, moles of MEA= $\frac{1.24}{61.08} = 0.02\ {}^{lbmole}/_{gal}$

Unstrapped $H_2S = \frac{0.0000757}{0.02} = 0.00378$, Unstrapped $CO_2 = \frac{0.0029}{0.02} = 0.145$

Assume ideal gas to calculate the partial pressure of H_2S and CO_2 in sour gas.

Partial pressure of H_2S

$= \frac{0.24984}{100} \times \left(\frac{760\,mmHg}{14.7Psi}\right) \times 1073Psi = 144\ mmHg$

Partial pressure for CO_2

$= \frac{1.19928}{100} \times \left(\frac{760\,mmHg}{14.7Psi}\right) \times 1073Psi = 665.5mmHg$

The ratio of acid gas partial pressure $R_v = \frac{144}{665.5} = 0.216$

Now calculate the concentration of MEA at the bottom:

Following this ascertain the equilibrium composition H_2S at 144 mmHg and 50°C and R_v=0.216

Campbell (1979) recommends the assumption of rich amine temperature leaving the absorber at 60 C°. Thus, equilibrium composition of H_2S in amine solution can be derived from Figure 4 and Figure 5 as well.

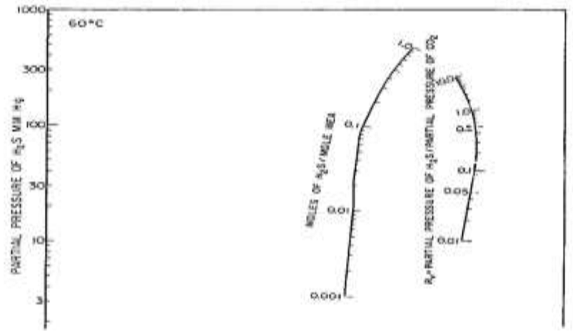

Figure 1: Equilibrium data for H_2S and MEA [4].

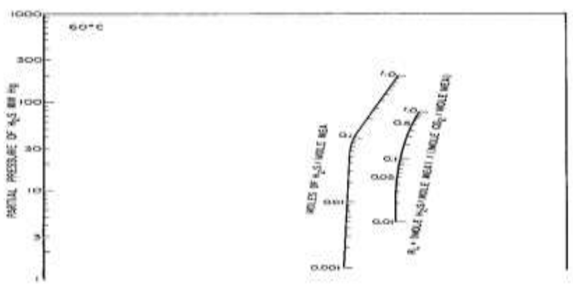

Figure 5: Equilibrium data for CO_2 and MEA [4].

From Figure 4, moles of H_2S per Moles of MEA = 0.07

From Figure 5, R_L = 0.12. Thus moles of CO_2 per MEA = 0.07/0.12= 0.583

Using the 70% approach of equilibrium will reveal the concentration of H_2S and CO_2 in rich amine.

0.07 x 0.7 = 0.049 moles of H_2S/ moles of MEA

0.583 x 0.7 =0.4 moles of CO_2/ moles of MEA. Total moles of acid gases per mole of MEA = 0.45

Net moles of H_2S / mole of MEA pick up in absorber = (concentration in rich MEA - concentration in lean MEA) = 0.049 - 0.00378= 0.045

Net moles of H_2S / mole of MEA pick up in absorber = (concentration in rich MEA - concentration in lean MEA) = 0.4 – 0.145 =0.255

Therefore moles of acid gases pick up in absorber / mole of MEA= 0.045+ 0.255= 0.3

The total amount of acid gas to be removed is as follows:

First convert gas flow rate into SCFM= $= \frac{2850000\,m^3}{day} \times \frac{35.314\,ft^3}{m^3} \times \frac{day}{24\ hr} \times \frac{hr}{60\ min} = 69892.3\ Scfm$

Thus, H_2S flow rate $= 0.24986\% \times 69892.3\ Scfm = 174.5\ Scfm$

CO2 flow rate x $= 1.199\% \times 69892.3\ Scfm = 838\ Scfm$, Or:

Moles of H_2S/min $= 174.5/380 = 0.45\ moles\ H2S/min$,

Moles of CO_2/min= $838/380 = 2.2\ moles\,CO2/min$

Therefore, the total moles of Acid per min= 2.65. Assuming all acid gases is absorbed by MEA

$\frac{moles\ of\ H2S\ per\ min}{net\ moles\ of\ H2S\ pick\ up\ per\ mole\ of\ MEA} = \frac{0.45}{0.045} = 10\ \frac{moles\ of\ MEA}{min\ needed\ for\ H2S}$

$\frac{moles\ of\ CO2\ per\ min}{net\ moles\ of\ CO2\ pick\ up\ per\ mole\ of\ MEA} = \frac{2.2}{0.255} = 8.6\ \frac{moles\ of\ MEA}{min\ needed\ for\ CO2}$

$\frac{moles\ of\ total\ acide\ gas\ per\ min}{net\ moles\ of\ acid\ gas\ pick\ up\ per\ mole\ of\ MEA} = 2.65/0.3 = 8.83\ \frac{moles\ of\ MEA}{min\ needed\ for\ acid\ gases}$

(Moles of MEA / min needed for H_2S)/ Moles of MEA / gal = $\frac{10}{0.02}$= 500 gpm

(Moles of MEA / min needed for\or CO_2)/ Moles of MEA / gal= $\frac{8.6}{0.02}$= 430 gpm

(Moles of MEA / min needed for total acid gas) / Moles of MEA / gal= $\frac{8.83}{0.02}$= 441.5 gpm

Add 10% for safety (Stewart & Arnold, 2011). Thus, 441.5 x 0.1= 485.65 gpm

Therefore, the design circulation rate of 15% MEA solution will be 490 gpm = 111 m^3/hr

V. Material balance

It is relatively important to achieve mass balance for the absorber column in order to examine all amine contactor streams and ascertain the acid gas composition in the sweet gas stream. As a result, mass balance will show whether or not the 15% MEA is active to remove acid gases from the sour gas stream.

Estimating solubility of Methane and Ethan in 15% MEA [7].

Results Methane concentration 5.79 (lbmole /100000 lbs solution) & Ethane concentration 0.303 (lbmole /100000 lbs solution).

MEA solution flow rate = 490 gpm = 705600 gal/day,
Density of MEA solution = 8.35 lb/US gal
705600 gal/day x 8.35 lb /US gal =5891760 lb/day
Thus, the total amount of Methane soluble in MEA solution

$$= \frac{5.79}{100000} \times 5891760 \times 16.04 \times \frac{1}{2.204} = 2492\ kg/day$$

Thus, the total amount of Ethane soluble in MEA solution

$$= \frac{0.303}{100000} \times 5891760 \times 16.04 \times \frac{1}{2.204} = 131.5\ kg/day$$

Now apply mass balance for acid gases

15 %(w/w) MEA is used. Thus, 85 % (w/w) water is used

Water flow rate =490 x 60x 24 x 0.85 x 8.35= 5007996 lb/day x 1kg/2.204lb = 2272230.5 kg/day
MEA flow rate =490 x 60x 24 x 0.15x8.35==883764lb/day x1kg/2.204lb= 401710.9 kg/day
As Kohl & Riesenfeld (1999) noted, H_2S normally reduces to less than 25 grain per 100 SCF = 4ppm and for CO_2 less than 2% (Stewart & Arnold, 2011). H_2S content in feed gas (sour gas):
Kmols of H_2S / day = 317.88 kmols/ day (table 9).
H_2S content in the gas out (sweet gas) should be :

$$\frac{Total\ gas\ flowrate\left(\frac{m^3}{day}\right)}{100\,m^3} \times \frac{0.6}{1000}\,kg = \frac{2850000 m3/day}{100} \times \frac{0.6}{1000} = 17.1\,\frac{kg}{day}$$

Thus H_2S to be removed = 10832.136 - 17.1 = 10815.036 kg/day
Number of mole of day without acid gases = 125301.8078 kmoles / day
The volume = 125301.81 x 22.414 = 2808514.769 m3/ day
By using previous methods for gas water content it can be established that water content at pressure 71 bars, 38 C° is 965.5 Kg/ MMstd. m^3. Water content for sweet gas = $2808514.769\ m^3/day$ x 965.5 Kg/ MMstd. M^3 = 2711 kg / day
The above results are applied in MS Excel to establish whole system compositions and quantities (see results section for more results).

VI. Results

This case study examines a moderate sour gas stream which contains around 2500 ppm H_2S and around 1.2 % CO_2. Moreover, 15% MEA solution is used for the sweetening process. As a result, the amine circulation rate calculated which is around 490 gpm (111 m^3/hr). Moreover, this amine circulation rate is considered economical for the sweetening process and does not need excessive amounts of energy.

Table 3: shows material balance results

	Sour gas inlet			Lean MEA solution			Sweet gas			Rich MEA solution		
componenets	kg/day	kmol/day	mol%	kg/day	kmol/day	mole%	kg/day	kmole/day	mole%	kg/day	kmole/day	mole%
CH_4	1867509	116573.5701	91.62512	0	0	0	1865016.6	116418	92.86549	2492	155.5556	0.114473
C_2H_6	116616.2	3878.156509	3.048174	0	0	0	116484.67	3873.783	3.090078	131.5	4.373129	0.003218
C_3H_8	42606.83	966.3603105	0.759545	0	0	0	42606.826	966.3603	0.770856	0	0	0
C_4H_{10}	19214.29	330.5969483	0.259844	0	0	0	19214.295	330.5969	0.263714	0	0	0
CO_2	67151.87	1525.832069	1.199282	52194.87	1184.094	1.91398	2721.1809	61.83097	0.049322	116625.55	2649.978	1.950108
H_2S	10832.14	317.8816811	0.24985	897.0109	26.32383	0.032893	17.1	0.509445	0.000406	11712.047	343.7037	0.25293
N_2	99758.9	3560.274828	2.798324	0	0	0	99758.901	3560.275	2.839996	0	0	0
H_2O	1370.85	76.15833333	0.059859	2272230.5	126235	83.32243	2711	150.6111	0.120141	2270890.4	126160.6	92.84102
MEA	0	0	0	401710.9	6553.196	14.73069	0	0	0	401710.9	6574.646	4.838254
total	2225060	127228.8308	100	2727033.3	133998.6	100	2148530.6	125362	100	2803562.4	135888.8	100

From table 3 results, it can be argued that the use of 15% MEA with 490 gpm (111m^3/hr) amine circulation rate may be considered effective with regards the removal of acid gases from the natural gas stream. As is shown in the table above, the H_2S content of the sweet gas stream is around 4 ppm, thus meeting the gas pipeline specifications and gas sale contracts. In addition, CO_2 content is approximately 0.049%, which is also considered an acceptable value and comfortable values with gas pipeline specifications.

VII. Conclusion

In conclusion, natural gas is considered one of the most popular fuels of recent eras. However, most natural gas reservoirs around the world produce sour natural gases which contain several acid gases such as H_2S and CO_2. This study is examined gas removal process calculations for natural gas stream with moderate acid gas contents. Moreover, amine gas sweetening is designed to sweeten this gas stream by using 15% MEA solution as alchemical solvent to remove acid gases. A 15% MEA solution circulation rate is calculated which is equal to approximately 490 gpm. It can be argued that 15% MEA solution and 490 gpm amine rate is effective in reducing acid gas content in a given natural gas stream which contains around 4 ppm for H_2S and 0.049 % CO_2.

VIII. References

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